

AR56

Pacific
Northern
Gas Ltd.

Annual
Report
1998

connec+ions

Map of Operations

- Pacific Northern Gas Mainline
- - - Pacific Northern Gas Lateral Line
- Mainline Looping
- Compressor Station
- PNG (N.E.)
- - - Centra Gas Fort St. John
- Peace River Transmission Company
- △ Gas Processing Plant
- Westcoast Energy

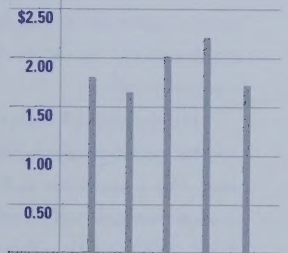


connect+ing experience

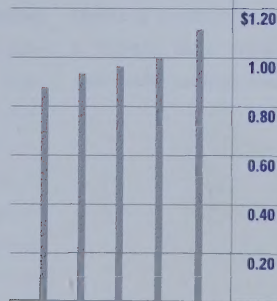
PLAN VIEW

SCALE: $\frac{3}{16}" = 1'-0"$

to opportunity



Earnings per Common Share



Dividends per Common Share

Report to Shareholders

While financial results for 1998 were not as positive as expected, Pacific Northern's management team remains optimistic about the future.

Natural gas deliveries to our residential and commercial customers were influenced by the unusually warm weather of 1998. Deliveries to two of our largest customers fell below projected levels as a result of operational difficulties for one and financial challenges for the other. In addition, the province-wide economic downturn negatively affected gas consumption by a number of other customers. Situations of this nature, especially when experienced simultaneously, result in lower than expected results.

Despite reduced deliveries, the year may be viewed positively for many reasons. Our transmission and distribution systems provided high levels of operational performance. Targeted system extensions and upgrades were completed. Planned progress was achieved in updating our administrative systems. We were successful in implementing a program of tight cost control. Also, recent additions to the management team provide a strong and dynamic resource which may

be counted upon to shape the Company's future and to permit us to aggressively pursue opportunities in new as well as traditional business enterprises.

1998 Operations review

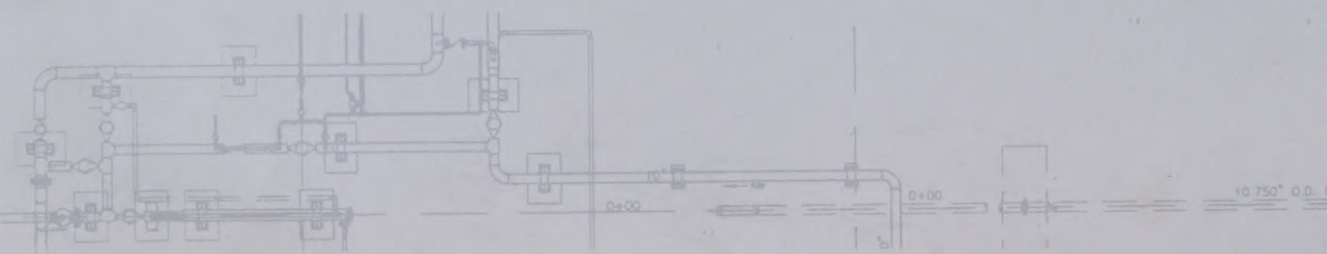
Operational highlights in 1998 included the addition of 1,140 customers to the system. Particularly strong growth was achieved in Fort St. John, with a record number of new customer attachments. Also in the Fort St. John area, we have been able to secure additional gas supply for our distribution system from a new transmission line. This connection will permit us to avoid the costly reinforcement of our own transmission system between Taylor and Fort St. John.

The Company pursued an active construction and rehabilitation program in 1998. Projects included installation of a 180-metre aerial crossing of the Gitnadoix River to replace the temporary crossing installed following a washout of the mainline in 1997. In a nearby channel of the Skeena River we directionally drilled to replace a 1000 metre portion of the mainline which

was jeopardized by the shifting river channel. Investigation of stress corrosion cracking continued, and several sections of pipe were replaced or remediated. A number of other engineering and construction projects on the system were completed according to plan.

On the administrative front we completed implementation of a new financial information system. Work continues at this time to place a new customer billing and information system into service later in 1999. In combination with the thorough review and upgrading of control systems and computer software and hardware, these systems are intended to assure the Company's preparedness for Year 2000.

During 1998, we initiated the process to merge Peace River Transmission Company Limited, Pacific Northern Gas (N.E.) Ltd. and Centra Gas Fort St. John Inc. This is expected





Management team, from left: Gerry Atkinson, Director Human Resources and Administrative Services; Patrick Horner, Comptroller; Roy Dyce, President and Chief Executive Officer; Peter Midgley, Manager Planning and Special Projects; Greg Weeres, Vice President Operations and Engineering; and Craig Donohue, Director Regulatory Affairs and Gas Supply.

to be complete by mid-1999. In addition, we have applied to the British Columbia Utilities Commission to establish a single tariff for customers in the Dawson Creek and Fort St. John areas. Efficiency will be gained through merging the companies and combining their operations. Taking into account the proximity of the two communities, we plan to divide a number of specialized functions between the two locations.

New leadership assesses opportunities ahead

During the past year, we increased our emphasis on the process of preparing the Company to meet the challenges and prosper in the business environment of the future. In part, this was stimulated by additions to our management team resulting from retirements and changes in our organizational structure. Approximately one-half of our senior management team joined the Company

within the past year, including our Vice President Operations and Engineering, Comptroller, Director of Human Resources and two field Operations Managers. The process of familiarizing these individuals with the Company necessitated careful definition of our plan and strategies and presented an ideal opportunity for reassessment.

Partly as a result of our staffing changes, we recently completed a comprehensive internal review of our organizational structure. This led to reassignment of a number of financial and administrative functions to the field, as well as a leveling of the reporting structure in our western service area. These changes improve both our operating efficiency and our ability to interact with customers and suppliers.

Strategic priorities

At a strategic level we are well advanced in a comprehensive review of our plans for the future. These plans include a commitment to effective management and the promotion of growth of our existing, regulated transmission and distribution systems. Knowing that expansion of our main transmission line will result in lower unit costs, we will continue to encourage new industrial development in our service corridor. Similarly, we will continue to focus our attention on servicing new construction and the extension of distribution lines into rural areas. But these responses form only part of the strategy for positioning Pacific Northern for the future.

Other strategic issues we are addressing include change of our business focus and contingency planning around business risks. At the present time, policy options and a number of potential targets in the areas of acquisition and diversification are under active review. The management team will present these to the Board of Directors during 1999, and seek its guidance and support for recommended options.

Non-regulated transmission pipelines are representative of the type of ventures we are likely to pursue in the future. Recently, we conducted a review of one such project in the Fort St. John area. While construction will not proceed at this

time due to a change of circumstances for a potential customer, the experience has provided us with a valuable model for future reference. Before placing the work on hold, we had successfully applied to exempt the proposed system from utility regulation. There is considerable upside in projects of this type. We are seeking similar opportunities and will proceed when it is prudent to do so.

Aboriginal initiative launched

At Pacific Northern, we recognize the need to respect and accommodate Aboriginal interests. Throughout our history we have enjoyed positive relationships with Aboriginal people and, over the years, we have been able to extend natural gas distribution service to a number of their communities.

Recent events have reinforced the importance of relationships between Canadian businesses and Aboriginal groups. Recognizing this, we have joined with other companies in the Westcoast Group in launching an Aboriginal relations initiative. We are committed to expanding our business relationships with Aboriginal enterprises

and to assuring continuing opportunities for participation of Aboriginals in our labour force. Also, at both the corporate and individual employee levels, we will be seeking opportunities for increasing liaisons with Aboriginal people, organizations and communities.

Acknowledgements

Several long-term and senior employees retired from the Company during 1998. Each devoted an important part of his life to Pacific Northern and made a significant contribution to the Company's development and evolution. For their loyal service, I wish to acknowledge and thank our former Vice President, Bill Hough, Comptroller, Tom Weaver, Operations Managers Wayne Epp and Wayne Hiebert, and Technical Services Superintendent, Ron Murphy.

With deep regret, I also wish to acknowledge our Junior Engineer, David Stanonik. David died when his vehicle was hit by another on December 21st. At the time, he was working on a Company project near his hometown of Fort St. John. Ever-cheerful, David was a very competent young engineer.

His enthusiasm and good nature will not be forgotten by those who had the opportunity to work with him and he will be greatly missed. Our new gas transfer station at West Stoddart, which was designed and constructed under David's supervision, has been named Stanonik Station in his memory.

I wish to thank our employees for their effort and dedication, and to recognize their skills and creativity. I also wish to recognize our Board for its wisdom and guidance. Collectively, these groups provide a sound basis for confidence in your Company's future success.

Roy G. Dyce

President and Chief Executive Officer

Vancouver, British Columbia

March 2, 1999



In the challenging terrain between Terrace and Prince Rupert, system reliability has been enhanced by the 1998 completion of this aerial crossing of the Gitnadoix River as well as a directionally drilled pipe replacement in a channel of the Skeena River and pipe replacements in the Khyex Valley.



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vision and
value



Management's Discussion and Analysis

Financial performance

Pacific Northern's net income in 1998 was \$6.45 million, compared with 7.93 million in 1997. After providing for preferred share dividends, earnings per common share were \$1.73 compared with \$2.16 in the previous year. Dividends paid to common shareholders were \$1.10 compared with \$1.00 per share in 1997. The change reflects an increase in the quarterly dividend rate from 26 to 28 cents per share in the second quarter of 1998.

The primary factor resulting in the reduction in net income was a reduction in gas deliveries.

Gas deliveries

Natural gas deliveries totalled 38.8 petajoules during 1998, compared with 42.3 petajoules in 1997. The reduction in deliveries is attributed to:

- the warmer than average weather that was experienced throughout the Company's service areas. Deliveries to temperature-sensitive core market customers fell from 7.0 petajoules in 1997 to 6.6 petajoules;
- a decline in volumes delivered to the Company's largest customer, Methanex Corporation, from 25.8 petajoules in 1997 to 22.2 petajoules. Startup delays were encountered following a planned maintenance shutdown at the customer's methanol/ammonia complex in Kitimat;
- a decline in volumes delivered to the Company's third-largest customer,

Skeena Cellulose Inc., from 2.9 petajoules in 1997 to 2.4 petajoules as a result of the financial and marketing challenges which were encountered during the year; and,

- the reduced gas consumption by a number of small and mid-size transportation service and gas customers, reflecting the impact of a province-wide economic downturn.

During 1998, the Company's four largest customers accounted for 54 percent of the gross operating margin. This marks the continuation of a favourable downward trend and reflects a diversification of the customer base resulting primarily from the addition of the Fort St. John distribution system.

Off-system sales of 0.8 petajoules of natural gas were arranged in 1998. These sales take place when contracted gas volumes exceed the requirements for core market customers and additions to the Company's underground storage reserves. Revenue from these sales is used to reduce the rates for core market customers.

Gas supply

All of the Company's residential customers, most of its commercial customers and a number of its industrial customers continue to rely on the Company for arrangement of their gas supply, and pay tariffs which include gas supply and service costs. From the Company's perspective, as the cost of gas is passed through to customers in rates and subsequent rate adjustments, involvement in gas supply has little impact on financial performance.

Pacific Northern's larger customers typically arrange for their own firm gas supplies and contract for transportation service on the Company's system. There was no significant change in the group of industrial and commercial customers electing this option during 1998. A number of these customers also purchase gas from the Company when available supply is surplus to the needs of core customers, or arrange interruptible transportation service if capacity is available on the system.

All of the Company's gas supply is produced in British Columbia. To meet the requirements of its core market customers, natural gas is purchased under long-term, short-term and spot contracts. Contracted gas that is surplus to the requirements of these customers in non-peak periods is either sold on an interruptible basis, directed to underground storage or sold off-system. The

use of storage provides a hedge against price volatility and an opportunity to minimize the cost of firm gas supply.

Natural gas is purchased at prevailing market prices. Variances in gas purchase prices from those included in current retail rates are deferred for subsequent refund to or recovery from customers.

The majority of the Company's gas supply is comprised of the pooled gas stream available from Westcoast Energy's transmission pipeline system. However, in Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities. Commencing in December 1997, the Company arranged to receive a portion of its Dawson Creek supply from a local producer of sweet (pipeline quality) gas at a point where its system intersects with Pacific Northern's transmission line. In Fort St. John, the Company installed Stanonik Station during 1998 to gain access to a new third-party transmission line. Requirements for the Fort St. John system now include supply from this line.

A long-term contract with CanWest Gas Supply Inc. accounted for the majority of 1998 purchases. Other supplies included purchases under seasonal and spot arrangements.

Main extensions and customer additions

A total of 1,140 customers was added to the distribution systems during 1998 compared with 1,753 in 1997. While a decline was anticipated as a result of the success in past years in capturing conversion customers along mains which were installed under the Canada/British Columbia Infrastructure Works Program, the decline was compounded by the general economic downturn and a reduction in new construction activity. An exception was the Fort St. John area, where the economy remained buoyant, and a record 380 new services were installed.

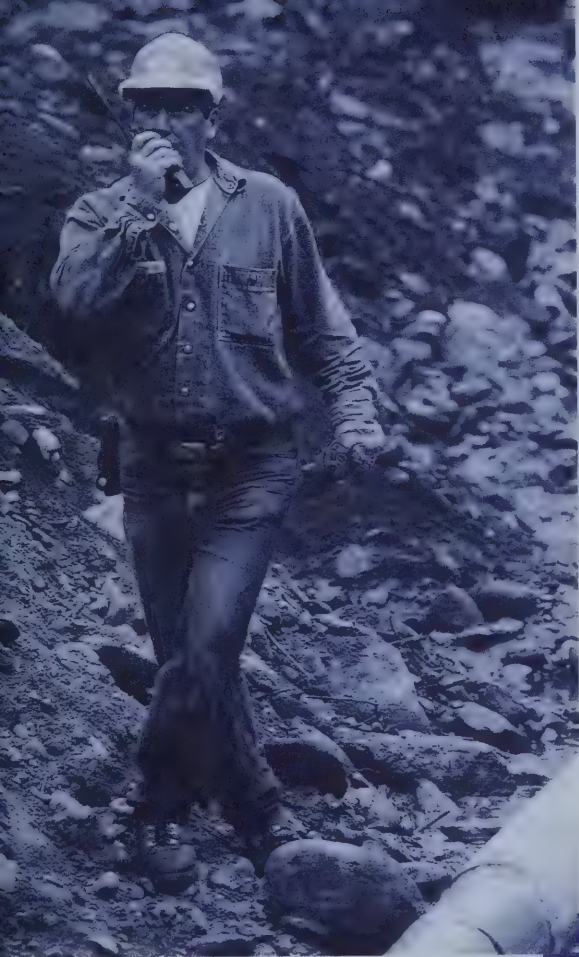
A total of 145 kilometres of gas main was installed during 1998. Included was the 26.6-kilometre Chindemash extension in the Terrace area, which was the final project eligible for funding under the Infrastructure Works Program. It will provide access to some 150 residential properties including the small community of Usk and 45 homes on Kitselas Band's Gitau's Reserve. Other active main extension areas included Fort St. James, Dawson Creek and Fort St. John, where extensions totalled 21, 22 and 53 kilometres respectively.

Engineering and operations

Planned rehabilitation continued during the year on the mainline between Terrace and Prince Rupert. Approximately one kilometre of pipe was replaced in the Khyex River Valley to reduce vulnerability to rock and land slides. The project was undertaken during a tight time window relating to fisheries protection, with continuation and completion planned during 1999.

Also between Terrace and Prince Rupert, directional drilling was successfully utilized to replace a one-kilometre section of the mainline that was jeopardized by shifting channels of the Skeena River. The project was completed in conjunction with nearby construction of a trussed aerial crossing of the Gitnadoix River, which was required to replace the temporary crossing that had been installed in December 1997 following the washout of the original crossing.

The Company continued its stress corrosion cracking (SCC) management program during 1998. A number of corrosion colonies were identified during digouts downstream from compressor stations at Burns Lake and Telkwa. Findings were consistent with expectations based on experience gained during the previous two years. Pipe replacements and remediation were completed as required. Management believes it has a good understanding of the portions of the transmission system likely to be at risk from SCC and has an appropriate remediation strategy in place. Current plans call for the continuation of examinations and testing during 1999 and 2000.



A multi-year project to replace and relocate a number of mainline sections located in steep river valleys between Terrace and Prince Rupert is scheduled for completion in 1999.

On the Western transmission and distribution system, various maintenance and improvement projects were completed in 1998. Electronic inspections were conducted on the 10-inch mainline through the Telkwa Pass and the 6-inch Kitimat lateral. A routine overhaul was conducted on the turbine at the Burns Lake compressor station. To assure the quality of gas delivered to the Methanex complex, a new filter unit was installed in Kitimat.

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Construction of a transmission line through the Fort St. John area by Novagas Canada Ltd. provided an opportunity to obtain gas supply reinforcement for the Fort St. John distribution system. To permit the transfer of gas into its system, the Company commissioned Stanonik Station in November. Provision has also been made to transfer gas between the two systems in Taylor in the unlikely event of disruptions in the normal supply pattern. An additional interconnection with the Novagas line is planned for 1999. Access to this new gas supply permits avoidance of costly reinforcement of the Company's supply line between Taylor and Fort St. John – an option that had previously been under consideration.

Regulatory activities

As reported in the 1997 Annual Report, Pacific Northern filed a cost of service allocation study and a revenue requirements application for the western transmission and distribution system in November 1997. An alternative dispute resolution process was conducted in February 1998, in which interested parties failed to reach agreement. A public hearing before the British Columbia Utilities Commission followed in April. Prior to the hearing, taking into account

the position of intervenors, the Company withdrew portions of its revenue requirements application relating to its proposal of a multi-year performance-based regulatory framework.

The Commission issued its decision on cost allocation and revenue requirement issues in June 1998. With respect to cost allocation, the Commission authorized the Company to commence adjustments of residential, commercial and industrial rates, with overall increases for some rate classes subject to offsetting reductions for others. Implementation of future adjustments would be subject to the proviso that the total increase in revenue for any customer class must not exceed ten percent per annum. The decision is in line with the Company's objective of adjusting rates to more appropriately reflect the costs of serving each customer class.

In the June decision, the common equity percentage allowed for rate-making purposes was set at the actual proportion subject to a maximum of 36 percent. The Company's actual common equity in 1998 was approximately 37.5 percent.

Also in its June decision, the Commission denied the Company's application for a deferral account in which to record any variance between the projected and actual operating margins for deliveries to Skeena Cellulose during 1998. The Company reapplied

for a deferral account, citing changed circumstances subsequent to the date of the Commission's decision. In its decision on the latter, the Commission authorized establishment of a deferral account with respect to deliveries made after the date of the initial decision. Disposition of the account will be determined by the Commission at a future date.

A special gas supply arrangement was made with BC Hydro to provide base load gas supplies to its Prince Rupert gas turbine generating plant. The revenue earned on deliveries in excess of a minor provision for standby deliveries was recorded in a deferral

account for future disposition. The BC Hydro deferral account balance was used to offset the Skeena Cellulose 1998 deliveries deferral account.

The rate of return on common equity was adjusted by the Commission on the basis of a predetermined relationship to long-term government debt. The allowed rate of return on common equity for 1999 is 10.0 percent for the PNG-West, Dawson Creek and Tumbler Ridge systems and 9.5 percent for the Fort St. John system. The issue of return on common equity and mechanisms for its adjustment will be the subject of a broad-based review at a proceeding to be conducted by the Commission during 1999.

In November 1998, the Company filed a cost of service allocation and rate design study pertaining to the Fort St. John and Dawson Creek service areas. In addition to updating information on cost factors, a primary objective of the submission is to provide a case for integrating the rates of these service areas. This would result in common rate classes and tariffs for services in the two nearby communities.

Complementing the proposal for a common rate structure for Fort St. John and Dawson Creek was a mid-December application to the Commission seeking approval to amalgamate Centra Gas Fort St. John Inc., Pacific Northern Gas (N.E.) Ltd. and Peace River Transmission Company Limited into a single corporate entity.

Revenue requirement applications for 1999 were filed at the beginning of December for all of the Company's service areas. The revenue requirements for 1999 were settled through negotiations with the customers under alternate dispute resolution processes supervised by Commission staff. The rate integration application for the Fort St. John and Dawson Creek areas is also expected to be settled through discussions with our customers.

Information systems

Pacific Northern took a number of steps during the past year to address its current and future requirements for computer-based information systems.

A project to upgrade the Company's financial information system was completed by year end. Full implementation has since occurred. The system supports requirements in areas such as payroll, purchasing and supplier transactions, inventory and tracking of fixed assets, and provides required outputs for gener-

al ledger entries, financial statements and reports. In addition to meeting Year 2000 requirements, it has permitted a transfer of work activity and responsibility to field offices.

Work continued in preparation for implementation of the Banner® customer interface system. The system is being modified to meet the requirements of Canadian gas utilities by a Westcoast subsidiary, Enlogix Inc. It will support customer billing and remittance processing, as well as providing the data-

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base for preparation of reports and management of gas meters. The opportunity to access the system through Enlogix will permit Pacific Northern to outsource a number of tasks and take advantage of economies that would not be available with an independently operated system.

In preparation for implementation of the Banner® system in 1999, several Company personnel have been trained in the new system. In addition to working on its customization to accommodate Pacific Northern's business processes, these individuals will be actively involved in training field personnel in system operation. Work has also proceeded in developing and testing programs that convert the current customer database, as well as upgrading communications systems and computer hardware. The new system is targeted for service in mid-1999.

Year 2000 compliance

A number of information technology and embedded logic systems which support Pacific Northern's operations are vulnerable to Year 2000 risks.

Pacific Northern has completed an inventory of all information technology and embedded logic systems which are operated by the Company. Significant progress has been made in remediation and testing or replacement of software, computers and electronic hardware. All embedded logic systems are expected to be ready by the end of the first quarter of 1999, and all computer-based systems by the end of the second quarter. As noted above, the Company has completed the upgrading of its financial information system to assure Year 2000 readiness and has made arrangements to replace its billing system.

The Company's preparation for Year 2000 has included contact with critical suppliers and major customers. As requested, the Company has also responded to enquiries from other organizations concerning its preparations.

Management is confident in its Year 2000 plan. However, it is recognized that successful operation of the Company's system is critically important to the public and the economy. Accordingly, steps have been taken to assure the availability of key personnel during critical time periods, and provision is being made for independent, manual control of key facilities should the need arise.

Year 2000 expenditures to date have totalled some \$200 thousand, with an additional expenditure of \$400 thousand anticipated in coming months.

Safety, environment and training

Pacific Northern's employees are routinely provided with training in safety and technical subjects. Many of the Company's employees were involved in a number of courses that were provided during 1998.

A Company-wide offering of the program "Our Responsibility: Our Environment", which was developed in conjunction with other companies in the Westcoast Group, was recently completed. It has provided all employees with a sensitivity to environmental issues and training relevant to their job responsibilities.

An independent consultant conducted a review of Pacific Northern's Environmental System during 1998. The report was generally positive concerning the Company's environmental management approach. The consultant recommended completing a detailed risk assessment and developing performance indicators to track environmental performance. In response, an internal Environmental Management Committee has recently been formed. Its mandate includes the responsibility of fully addressing the consultant's recommendations.

Internal organizational review

During the year, the Company conducted an internal review of its organizational structure. This included documentation of internal and external business interactions of all employees, and an analysis of reporting structures. The review endorsed some planned changes and identified a number of other changes, all of which have been implemented or are underway at this time. Included are the transfer to field offices of responsibilities for various accounting and payroll functions.



A welder completes a connection between a pedestal and the bridge structure on the new Gitnadoix River crossing.

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company and
shareholder
strength



Certain billing and remittance processing activities will also be moved to field offices in conjunction with implementation of the Banner® customer interface system. Other activities are the relocation and reorganization of the Company's safety and training resources and consolidation of the management structure in the Company's western service area.

Performance compensation

All of the Company's permanent employees are eligible for incentive compensation in addition to their basic salary and benefit packages. Introduction of the Performance Compensation Sharing (PERCS) Plan in 1997 provided bargaining unit employees with their first incentive payments in 1998. These payments are based on corporate performance as measured against targets for earnings per share, control of operating costs and safety performance.

In addition to eligibility for incentive compensation based on the same performance indicators recognized in the PERCS Plan, non-bargaining unit employees participate in a short-term incentive plan. Payments are based on each individual's personal success during the year in achieving predetermined stretch objectives.

Performance compensation is viewed by management as an important strategy in aligning the interests of employees with corporate performance.

Operating activities

Additions to property, plant and equipment totalled \$10.6 million in 1998 compared with \$9.1 million in 1997.

Operating, maintenance and administrative costs totalled \$16.7 million, an increase of \$0.6 million relative to 1997. In addition to higher costs associated with inflation and customer account growth, the increase reflects the additional costs of Year 2000 preparation and a greater focus on pipeline rehabilitation and maintenance. As a result of lower gas deliveries, cost increases were partially offset by the reduced consumption of fuel gas used in operations.

Liquidity and capital resources

The Company's investment activities are financed by cash generated from operations, together with proceeds from the issue of long-term debt and share capital.

Junior preferred shares were redeemed in the amount of \$3.3 million. The redemption arises from the application of losses acquired in 1996, which generated income tax savings of \$0.4 million in 1998.

Pacific Northern has a bank line of credit in the amount of \$35 million. This provides working capital as well as interim financing for capital programs.

Alternative dispute resolution

A Commission-organized process in which interested parties seek an agreed settlement of issues without the need for a formal public hearing.

British Columbia Utilities Commission

This provincially appointed body regulates capital programs, operations and earnings of the energy utilities in British Columbia.

Core market

Residential, commercial and small industrial customers for whom the Company plans and arranges gas supply and transmission and distribution capacity to meet peak requirements.

Firm gas

The industry term for gas which must be delivered without interruption under contractual obligations. It is gas guaranteed to be delivered regardless of fluctuations in seasonal demand.

Gigajoule (GJ)

A metric measurement of energy used for routine customer billing; one billion joules.

Interruptible sales/service

Delivery of natural gas subject to the availability of gas supply and capacity on the Company's system. Sales involve gas which is surplus to the requirements of core market customers, or purchased in the spot market. Service involves delivery of gas supply arranged by the customer in excess of the volume for which they have contracted for firm delivery by the Company.

Looping

The addition of a second pipe connected in parallel to an existing pipeline to increase capacity through a reduction in pressure loss.

Metric to imperial conversions

1.0 GJ = 0.94782 MMBtu

1.0 10³m³ = 35.301 Mcf

Off-system sales

Sales of natural gas contracted by the Company (and periodically surplus to requirements of core market customers) to purchasers who will obtain delivery through other pipeline systems.

Petajoule (PJ)

One million gigajoules.

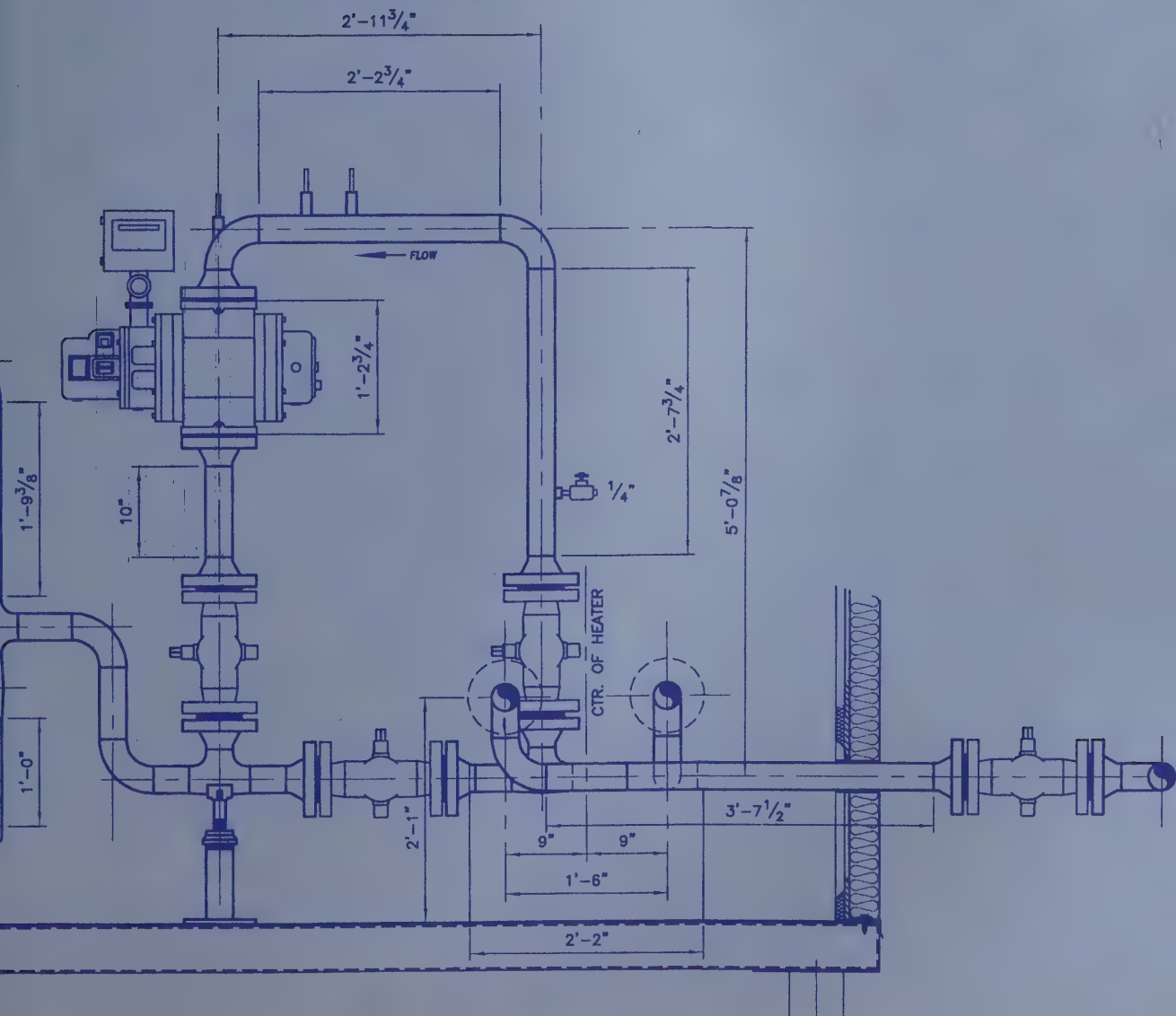
Terajoule (TJ)

One thousand gigajoules.

Transportation customers

Large industrial and commercial customers who contract with the Company for pipeline capacity and make their own arrangements for supply of gas and its delivery to the Company's system.

financial statements



Auditors' Report

To the Shareholders of Pacific Northern Gas Ltd.

We have audited the consolidated balance sheets of Pacific Northern Gas Ltd. as at December 31, 1998 and 1997 and the consolidated statements of income, retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing stan-

dards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position

of the Company as at December 31, 1998 and 1997 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied on a consistent basis.

Ernst & Young LLP

Chartered Accountants

Vancouver, Canada,
January 29, 1999.

Responsibility for Financial Statements

The accompanying financial statements were prepared by management of the Company in conformity with generally accepted accounting principles applied on a consistent basis. Management is responsible for the integrity and objectivity of the information contained in the financial statements. Management is also responsible for installing and maintaining appropriate internal controls, policies and procedures, which provide reasonable assurance that reliable financial information is produced and that the Company's assets are safeguarded. Ernst & Young LLP, Chartered Accountants, as the Company's external

auditors appointed by the shareholders, have examined the financial statements for the years ended December 31, 1998 and 1997, in accordance with generally accepted auditing standards and rendered their independent opinion thereon. The Audit Committee of the Board of Directors meets with the external auditors to review the manner in which they are performing their responsibilities and to discuss auditing, internal accounting controls and financial reporting matters. The external auditors have full access to the Audit Committee of the Board.

Consolidated Statements of Income

Years ended December 31 (<i>thousands of dollars</i>)	1998	1997
Operating revenues (<i>notes 1 and 10</i>)	\$ 72,144	\$ 77,861
Cost of sales (<i>note 10</i>)	20,887	27,295
Operating margin	51,257	50,566
Operating and maintenance	11,756	11,429
Administrative and general	4,951	4,722
Amortization of deferred charges	1,383	403
Municipal and other taxes	3,908	3,726
Depreciation	6,939	6,664
	28,937	26,944
Operating income	22,320	23,622
Investment and other income	145	116
	22,465	23,738
Income deductions:		
Interest on long-term debt	8,662	7,786
Other interest	790	1,233
	9,452	9,019
Income before income taxes	13,013	14,719
Income taxes (<i>note 3</i>)		
- currently payable	1,376	665
- deferred	5,183	6,128
	6,559	6,793
Net income for the year	\$ 6,454	\$ 7,926
For common shares		
Net income for the year	\$ 6,454	\$ 7,926
Provision for dividends on preferred shares	337	337
Net income applicable to common shares	\$ 6,117	\$ 7,589
Per common share (<i>note 5</i>)		
Basic	\$ 1.73	\$ 2.16
Fully diluted	\$ 1.69	\$ 2.10

See accompanying summary of accounting policies and notes

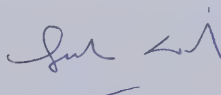
Consolidated Balance Sheets

As at December 31 (thousands of dollars)	1998	1997
ASSETS (note 8)		
Current assets		
Accounts receivable (note 1)	\$ 12,904	\$ 11,706
Due from Centra Gas British Columbia Inc. (note 10)	—	1,354
Inventories of supplies and natural gas	4,065	4,158
Prepaid expenses	571	587
	<u>17,540</u>	<u>17,805</u>
Plant, property and equipment (note 2)	<u>181,169</u>	<u>177,562</u>
Deferred charges		
Debt expense	888	889
Pipeline rehabilitation costs	2,802	3,086
Other	1,635	2,973
	<u>5,325</u>	<u>6,948</u>
	<u>\$ 204,034</u>	<u>\$ 202,315</u>

On behalf of the Board:



Roy G. Dyce
Director



Graham M. Wilson
Director

Consolidated Balance Sheets

As at December 31 (thousands of dollars)	1998	1997
LIABILITIES		
Current liabilities		
Bank indebtedness	\$ 19,547	\$ 17,237
Due to Westcoast Power Holdings Inc. (note 10)	—	1,829
Accounts payable and accrued liabilities	8,705	7,332
Income and other taxes payable	715	1,200
Long-term debt due within one year (note 8)	3,327	2,712
	32,294	30,310
Long-term debt (note 8)	88,894	92,135
Deferred income taxes	11,126	7,119
	132,314	129,564
Commitments and contingency (notes 11 and 13)		
SHAREHOLDERS' EQUITY		
Preferred shares (note 6)	10,261	13,609
Common shares (note 7)	8,836	8,821
Contributed surplus (note 7)	2,026	1,953
Retained earnings	50,597	48,368
	61,459	59,142
	71,720	72,751
	\$ 204,034	\$ 202,315

See accompanying summary of accounting policies and notes

Consolidated Statements of Retained Earnings

Years ended December 31 (thousands of dollars)	1998	1997
Balance, beginning of year	\$ 48,368	\$ 44,299
Net income for the year	6,454	7,926
	54,822	52,225
Preferred dividends	337	337
Common dividends	3,888	3,520
	4,225	3,857
Balance, end of year	\$ 50,597	\$ 48,368

See accompanying summary of accounting policies and notes

Consolidated Statements of Cash Flow

Years ended December 31 (thousands of dollars)	1998	1997
OPERATING ACTIVITIES		
Net income for the year	\$ 6,454	\$ 7,926
Add (deduct) items not involving cash:		
Deferred income taxes	5,183	6,128
Depreciation and amortization	8,322	7,067
Other	319	(546)
Operating cash flow	20,278	20,575
Non-cash working capital changes	(635)	(5,297)
Net cash provided by operating activities	19,643	15,278
INVESTING ACTIVITIES		
Additions to plant, property and equipment	(10,600)	(9,128)
Deferred charge expenditures	(1,241)	(1,738)
Acquisitions		
Centra Gas Fort St. John Inc. (note 9)	—	(15,108)
Other (note 9)	—	(410)
Net cash used by investing activities	(11,841)	(26,384)
FINANCING ACTIVITIES		
Issue of long-term debt	74	20,000
Repayment of long-term debt	(2,700)	(5,202)
Issue of common shares (note 7)	88	288
Redemption of junior preferred shares (note 6)	(3,348)	(5,301)
Dividends paid	(4,225)	(3,857)
Net cash (used) provided by financing activities	(10,111)	5,928
Increase in bank indebtedness during the year	(2,310)	(5,178)
Bank indebtedness, beginning of year	(17,237)	(12,059)
Bank indebtedness, end of year	\$ (19,547)	\$ (17,237)

See accompanying summary of accounting policies and notes

Summary of Accounting Policies

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, Pacific Northern Gas (N.E.) Ltd., Centra Gas Fort St. John Inc., Peace River Transmission Company Limited and PNG Marketing Ltd.

REGULATION

The Company, Pacific Northern Gas (N.E.) Ltd., Centra Gas Fort St. John Inc. and Peace River Transmission Company Limited are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission").

PLANT, PROPERTY AND EQUIPMENT

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. The cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are 2.9% [1997 - 2.8%] for transmission plant, 2.6% [1997 - 2.6%] for distribution plant, 5.1% [1997 - 5.1%] for general plant and 4.9% [1997 - 4.9%] for processing plant. Application of these rates for the year ended December 31 1998, resulted in a composite rate of 2.9% [1997 - 2.9%].

INVENTORIES OF SUPPLIES AND NATURAL GAS

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

DEFERRED CHARGES

(a) **Debt expense:** Debt expense comprises issue costs of long-term debt which are amortized on a straight-line basis over the term of the related issue.

(b) **Pipeline rehabilitation costs:** Pipeline rehabilitation costs are being amortized on a straight-line basis over ten years. The amount of such amortization in 1998 was \$567,000 [1997 - \$519,000].

(c) **Other:** Costs as required or permitted by the Commission have been deferred to be recovered from future revenues. Certain regulatory deferrals are subject to future decisions by the Commission, who will determine the treatment to be given the various items. During 1998, \$1,478,000 was charged to income [1997 - \$116,000 credited to income] in respect of these deferred costs.

In March 1997, an industrial customer, Skeena Cellulose Inc., obtained protection from creditors under the Companies' Creditors Arrangement Act. The Commission authorized the Company to record losses arising in both 1997 and 1998 from this event as deferred charges. At December 31, 1998, the deferred charges amounted to \$817,000 [1997 - \$826,000], net of income taxes and amortization. The deferred charges arising in 1997 are being amortized on a straight-line basis over three years commencing January 1, 1998. The ultimate realization of the deferred charges of \$279,000 arising in 1998 is subject to review and approval of the Commission.

INCOME TAXES

The Company provides for income taxes using the taxes payable method as directed by the Commission except as described below.

The Commission has directed that the tax allocation method of accounting for income taxes be followed by Pacific Northern Gas (N.E.) Ltd. and for certain transactions within the other regulated entities. Under the tax allocation method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

From July 1, 1978 until its suspension on November 1, 1986, the tax allocation method was followed by the Company. Had the tax allocation methodology been followed continuously since the inception of the Company, deferred income taxes recorded in the accounts would have been increased by approximately \$14,823,000 [1997 - \$15,155,000].

PENSION AND OTHER POST-RETIREMENT EMPLOYEE BENEFITS

Pension costs and obligations are determined annually by independent actuaries using management's best estimates. Pension assets are valued by using average market related values over a three-year period. Pension expense consists of current service costs and adjustments arising from plan amendments, changes in assumptions, and experience gains or losses which are amortized on a straight-line basis over the expected average remaining service life of the plan members.

Certain health care and life insurance benefits are provided for employees after retirement. The cost of these benefits is expensed as incurred.

Notes to Consolidated Financial Statements

1. MAJOR CUSTOMERS

The proportion of energy deliveries and revenues attributable to large industrial customers is as follows:

	1998		1997	
<i>Percent</i>	Energy	Revenue	Energy	Revenue
Methanex Corporation	58	31	61	32
Skeena Cellulose Inc., Eurocan Pulp and Paper Co. and Alcan Smelters and Chemicals Ltd.	16	12	15	13

At December 31, 1998, 19% [1997 - 25%] of accounts receivable was attributable to these four large industrial customers.

2. PLANT, PROPERTY AND EQUIPMENT

<i>Thousands of dollars</i>	1998	1997
Transmission plant	\$163,002	\$158,048
Distribution plant	68,313	64,706
General plant	15,848	15,093
Processing plant	2,607	2,559
Construction in progress	2,555	1,459
Total plant, property and equipment	\$252,325	\$241,865

Accumulated depreciation

Transmission plant	47,320	42,829
Distribution plant	15,822	14,139
General plant	6,265	5,709
Processing plant	1,749	1,626
Total accumulated depreciation	71,156	64,303
	\$181,169	\$177,562

During the year, the Company received contributions in aid of construction of \$1,902,000 [1997 - \$701,000] which have been recorded as a reduction of distribution plant.

3. INCOME TAXES

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

<i>Percent</i>	1998	1997
Corporate income tax rate	45.6	45.6
Benefit realized upon application of loss carryforwards	(3.5)	(4.0)
Large corporations tax	2.7	2.9
Depreciation in excess of capital cost allowance	2.6	1.9
Deferred income taxes recorded on regulatory deferred accounts	5.3	4.5
Deferred charge expenditures deducted for tax purposes	(2.2)	(5.3)
Other items	(0.1)	0.5
Income tax rate recorded in the accounts	50.4	46.1

4. PENSION PLANS

The Company and its subsidiaries have defined benefit pension plans covering substantially all employees. The plans provide benefits based on length of service and earnings. Pension costs of \$469,000 were charged to operations during 1998 [1997 - \$559,000]. At December 31, 1998, the actuarial estimate of the present value of accrued pension benefits was \$10,973,000 [1997 - \$10,052,000], and the market value for actuarial purposes of the assets available to provide these benefits was \$11,617,000 [1997 - \$9,934,000].

5. EARNINGS PER COMMON SHARE

Earnings per common share have been calculated after deducting preferred share dividend requirements from net income. Earnings per share on a fully diluted basis were calculated after allowing for the exercise of employees' options on Class A common shares.

Net income used in determining fully diluted earnings per common share has been increased by \$61,000 in 1998 [1997 - \$46,000] to give effect to an imputed after-tax return of 2.5% [1997 - 2.2%] on funds which would have been available on the exercise of options.

6. PREFERRED SHARES

Thousands of dollars	1998	1997
Authorized		
200,000 6¼% cumulative redeemable preferred shares with a par value of \$25 each		
1,400,000 cumulative redeemable junior preferred shares with a par value of \$10		
Issued		
200,000 6¼% preferred shares	\$ 5,000	\$ 5,000
526,091 junior preferred shares		
[1997 - 860,859]	5,261	8,609
	\$ 10,261	\$ 13,609

The 6¼% preferred shares are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption.

The junior preferred shares are redeemable on a quarterly basis in amounts equal to 90% of the tax savings realized from the utilization of the non-capital loss carryforwards arising from the acquisition in 1996 of all of the outstanding shares of Centra Gas Victoria Inc., a company related through common control. The Company may, at its option, satisfy the redemption requirements by issuing Class A non-voting common shares of the Company at an issue price per common share of 85% of weighted average trading price of the Class A non-voting common shares for the 20 business days preceding the date of the notice of redemption.

During 1998, the Company redeemed 334,768 [1997 - 530,124] junior preferred shares for cash consideration of \$ 3,347,680 [1997 - \$5,301,240].

7. COMMON SHARES

Thousands of dollars	1998	1997
Authorized		
6,000,000 Class A non-voting common shares with a par value of \$2.50 each		
20,000 Class B voting common shares with a par value of \$2.50 each		
Issued		
3,514,460 Class A common shares		
[1997 - 3,508,560]	\$ 8,786	\$ 8,771
20,000 Class B common shares	50	50
	\$ 8,836	\$ 8,821

During 1998, the Company issued 5,900 [1997 - 18,800] Class A common shares for cash consideration of \$88,000 [1997 - \$288,000] upon the exercise of employee options. Of this amount, \$73,000 [1997 - \$241,000] representing the excess of the issue price over the par value of the shares has been credited to contributed surplus.

During 1998, the Company granted 19,000 [1997 - 22,200] options to acquire Class A common shares at a price of \$30.00 [1997 - \$20.75] per share prior to March 24, 2008 [1997 - March 14, 2007].

At December 31, 1998, the following Class A common shares are reserved for issuance upon the exercise of options by employees:

Number of shares	Option price	Expiry date
13,160	\$ 10.7500	April 27, 2000
6,880	14.1250	January 28, 2002
7,800	15.7500	May 4, 2003
30,800	20.0000	November 7, 2005
20,800	18.7500	March 14, 2006
20,200	20.7500	March 14, 2007
19,000	30.0000	March 24, 2008

8. LONG-TERM DEBT

<i>Thousands of dollars</i>	1998	1997
Secured Debentures		
2002 Series, 10.85% due July 15, 2002, payable in annual instalments of \$2,000,000, with a final instalment of \$12,000,000 at maturity.	\$ 18,000	\$ 20,000
2011 Series, 10.75% due December 13, 2011, payable in annual instalments of \$700,000 and \$800,000 in each of years 2009 and 2010 with a final instalment of \$5,000,000 at maturity.	13,600	14,300
2018 Series, 8.75% due November 15, 2018, payable in annual instalments of \$600,000, commencing November 15, 1999 and \$1,000,000 in each of the years 2014 to 2017, with a final instalment of \$7,000,000 at maturity.	20,000	20,000
2025 Series, 9.30% due July 18, 2025, payable in annual instalments of \$500,000, commencing July 18, 2004 with a final instalment of \$9,500,000 at maturity.	20,000	20,000
2027 Series, 6.90% due December 2, 2027, payable in annual instalments of \$500,000, commencing December 2, 2006 with a final instalment of \$9,500,000 at maturity.	20,000	20,000
Construction advances and other	621	547
	92,221	94,847
Deduct long-term debt due within one year shown as a current liability	3,327	2,712
	\$ 88,894	\$ 92,135

[a] Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's fixed assets and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

[b] Payments required to meet sinking fund and retirement provisions during the next five years are as follows:

<i>Thousands of dollars</i>	
1999	\$ 3,327
2000	3,300
2001	3,300
2002	13,300
2003	1,300

[c] Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.

9. ACQUISITIONS

[a] **Centra Gas Fort St. John Inc.**

Effective January 1, 1997, the Company acquired all of the outstanding preferred and common shares of Centra Gas Fort St. John Inc., a company related through common control, and an \$8,000,000 loan owing by Centra Gas Fort St. John Inc. to Centra Gas Inc., a company also related through common control. The purchase price consisted of cash of \$15,108,000, including acquisition costs.

The acquisition has been measured at the exchange amount, which was negotiated by an independent committee of the Board of Directors, and has been accounted for by the purchase method as follows:

<i>Thousands of dollars</i>	
Plant, property and equipment	\$ 16,326
Deferred charges	120
	16,446
Less:	
Working capital deficiency	1,196
Customer deposits	142
	1,338
Purchase price	\$ 15,108

[b] Peace River Transmission Company Limited

Effective January 1, 1997, the Company acquired all of the outstanding common shares of Peace River Transmission Company Limited for cash consideration of \$291,000.

The acquisition has been accounted for by the purchase method as follows:

Thousands of dollars

Plant, property and equipment	\$ 302
Deferred charges	41
	343
Less:	
Working capital deficiency	52
Purchase price	\$ 291

[c] Granisle Propane System

During 1997, the Company purchased the plant, property and equipment and inventories of a propane distribution system located at Granisle, B.C. for cash consideration of \$119,000. The acquisition has been accounted for by the purchase method.

10. RELATED PARTY TRANSACTIONS [see also note 9]

The Company's transactions with related parties are as follows:

<i>Thousands of dollars</i>	1998	1997
Westcoast Energy Inc., parent company		
Transportation services	\$ 686	\$ 759
Materials and services	975	584
Interest on note payable	—	711
Centra Gas British Columbia Inc., a company related through common control		
Materials and services	189	464
Engage Energy Canada, L.P., an entity related through common control		
Natural gas purchases and services	821	2,780
Sales	723	2,014

These transactions are in the normal course of operations and are recorded at amounts established and agreed between the related parties.

The amounts due from Centra Gas British Columbia Inc. and due to Westcoast Power Holdings Inc. were non-interest bearing and due on demand.

11. NATURAL GAS AND INTEREST RATE CONTRACTS

The Company's tolls are set using a forecasted price for gas. However, the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices. At December 31, 1998, the Company has entered into natural gas price swap contracts to effectively fix the price for approximately 4.5% of its forecast 1999 system gas supply. In addition to the above mentioned swap contracts, at December 31, 1998, the Company has also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 9.0% of its forecast 1999 system gas supply. The difference between the price of gas used for toll purposes and the actual cost of gas purchased is deferred and refunded to or recovered from customers as directed by the Commission. The swap contracts have a fair value of \$127,000 receivable at December 31, 1998 [\$40,000 receivable at December 31, 1997]. The collar contracts have a fair value of \$74,000 payable at December 31, 1998 [\$nil at December 31, 1997]. The fair values reflect the estimated amounts that the Company would receive or pay to terminate the swap and collar contracts respectively at December 31, 1998, based on the estimated future net cash flows under the terms of each contract.

Tolls for customers of Centra Gas Fort St. John Inc. are predicated on \$8 million of long-term debt financing. Accordingly, the Company is party to an interest rate swap contract that converts the interest rate characteristics of \$8 million of short-term borrowings from floating to a fixed rate of 7.70% until October 2004. The swap contract has a fair value of \$985,000 payable at December 31, 1998. The fair value represents the amount the Company would have to pay to terminate the swap contract at December 31, 1998, based on the quoted market prices for similar instruments.

These estimated fair market values have no impact on earnings [see also note 12] due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility-related financial instruments would be treated as part of the cost of service.

12. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair values of debt instruments included in the consolidated balance sheets are as follows:

<i>Thousands of dollars</i>	<i>Carrying value</i>		<i>Fair value</i>	
	1998	1997	1998	1997
Long-term debt	\$ 92,221	\$ 94,847	\$ 107,830	\$ 111,863

The fair values of the Company's long-term debt are estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, due from Centra Gas British Columbia Inc.; bank indebtedness, due to Westcoast Power Holdings Inc.; and accounts payable and accrued liabilities approximate their carrying values.

13. CONTINGENCY

The Company has, since 1997, had an extensive program of review and remediation of computer systems and applications and key business processes in use throughout the Company in an effort to avoid Year 2000 problems which could cause material disruption to the Company's business. The review phase of the Year 2000 program has been completed and the Company is carrying out the remediation, testing and implementation phase. The Company is in ongoing communication with its customers, vital suppliers and other third parties to assess their level of Year 2000 readiness. However, it is not possible for the Company to be certain that all aspects of the Year 2000 issue affecting the Company, including those related to efforts of customers, suppliers or other third parties, will be fully resolved. The Company, therefore, is developing business contingency plans to allow it to carry on business in an orderly manner into the Year 2000. A Corporate Year 2000 Project Office has been in place at the Company's parent company headquarters since late 1997.

14. SUBSEQUENT EVENTS

The Company has applied for changes to its rates effective January 1, 1999. The allowed return on common equity for 1999 has been set at 10.00% [1998 - 10.75%] for the Company and Pacific Northern Gas (N.E.) Ltd. The allowed return on equity for 1999 for Centra Gas Fort St. John Inc. is 9.50% [1998 - 10.25%].

Ten-year Review

For the year ended December 31	1998	1997	1996	1995
DELIVERIES (TJ)*				
Residential	3 688	3 796	3 056	2 644
Commercial	2 897	3 162	2 559	2 217
Small Industrial	3 704	2 972	2 120	1 905
Large Industrial	28 498	32 365	30 981	27 890
Total energy delivered	38 787	42 295	38 716	34 656
Customers at year-end	38,808	37,669	27,978	26,638
AVERAGE RATES PER GJ*				
Residential	\$ 5.80	5.68	4.90	5.30
Commercial	4.41	4.41	3.58	4.58
REVENUE				
Residential	\$ 21,380	21,552	14,971	14,026
Commercial	12,763	13,952	9,157	10,161
Small industrial	4,912	4,848	3,354	4,013
Large industrial	31,883	35,166	33,842	30,237
Off-System	754	1,804	1,068	2,119
Other	452	539	431	442
	\$ 72,144	77,861	62,823	60,998
EXPENSES				
Cost of sales	\$ 20,887	27,295	14,975	19,943
Operating	20,615	19,877	16,611	16,518
Interest	9,307	8,903	8,822	8,915
Depreciation & amortization	8,322	7,067	6,792	5,646
Income taxes	6,559	6,793	8,238	3,785
	\$ 65,690	69,935	55,438	54,807
Net income	\$ 6,454	7,926	7,385	6,191
PER COMMON SHARE				
Earnings	\$ 1.73	2.16	2.01	1.67
Dividends	1.10	1.00	0.96	0.94
CAPITALIZATION				
Long-term debt	\$ 88,894	92,135	74,862	80,056
Deferred income taxes	11,126	7,119	1,863	15,514
Preferred shares	10,261	13,609	18,910	5,000
Common equity	61,459	59,142	54,785	51,038
Total capitalization	\$ 171,740	172,005	150,420	151,608
Utility plant				
In service (net)	\$ 178,614	176,103	156,995	154,421
Construction in progress	2,555	1,459	1,244	1,929
Total investment in utility plant	\$ 181,169	177,562	158,239	156,350

(Dollar amounts
are in thousands
except per
share and per
GJ figures.)

1994	1993	1992	1991	1990	1989	
2 580	2 336	1 510	1 517	1 392	1 259	* TJ refers to Terajoules and is equivalent to 1,000 GJ.
2 183	2 102	1 420	1 484	1 518	1 414	
1 924	1 984	1 574	1 518	1 456	1 479	
31 339	31 084	29 592	30 734	30 527	28 283	
38 026	37 506	34 096	35 253	34 893	32 435	
25,714	24,667	17,282	16,042	14,984	13,892	
5.31	5.03	5.15	4.83	4.56	4.50	* GJ refers to Gigajoules, a metric unit of energy equivalent to 10 ⁹ joules.
4.65	4.36	4.54	4.33	4.17	4.15	
13,708	11,740	7,770	7,321	6,349	5,666	
10,148	9,158	6,443	6,427	6,327	5,862	
3,903	3,665	2,486	3,048	3,985	4,569	
34,125	32,566	32,364	51,202	59,209	57,567	
—	—	—	—	—	—	
442	345	246	299	313	193	
62,326	57,474	49,309	68,297	76,183	73,857	
22,281	20,390	17,302	35,886	45,669	44,578	
16,527	16,143	13,096	12,037	11,148	11,223	
7,918	7,781	7,504	7,523	7,709	7,420	
4,969	4,420	4,136	3,805	3,819	3,563	
4,030	2,777	1,868	3,078	2,280	1,924	
55,725	51,511	43,906	62,329	70,625	68,708	
6,601	5,963	5,403	5,968	5,558	5,149	
1.80	1.63	1.48	1.67	1.56	1.44	
0.88	0.88	0.80	0.78	0.75	0.75	
63,990	67,937	51,875	55,817	42,763	44,937	
15,731	15,703	14,877	14,919	14,919	15,051	
5,000	5,000	5,000	5,000	5,000	5,000	
48,432	44,787	42,020	39,357	35,983	33,151	
133,153	133,427	113,772	115,093	98,665	98,139	
145,047	135,187	122,999	118,808	117,210	107,081	
2,590	1,789	1,028	1,553	1,108	1,129	
147,637	136,976	124,027	120,361	118,318	108,210	

Report on Corporate Governance

The bylaws of the Toronto Stock Exchange ("TSE") require that the Corporation disclose the corporate governance practices of its Board of Directors ("Board"). The following report addresses the principal responsibilities of a board of directors contained in the guidelines for corporate governance established by the TSE.

Through its Corporate Governance Committee, previously the Nominating and Corporate Governance Committee (the "Committee"), the Board will develop sound corporate governance practices to enhance corporate performance.

Board of Directors: The Board, as set out in its terms of reference, has the responsibility for overseeing the conduct of the business of the Company and the activities of management, which is responsible for the day-to-day operations of the business.

Composition of the Board: The Board is composed of nine directors. One of the directors is a full-time officer of the Company and three are full-time officers of the Company's parent, Westcoast Energy Inc. ("Westcoast"), which owns 100% of the voting common shares and is therefore considered a significant shareholder. The TSE Guidelines provide that a director related to a significant shareholder should not be considered a related director of the subsidiary company. The remaining five directors do not have interests in or relationships with the Company or its parent (other than interests and relationships arising from shareholdings) which could, or could reasonably be perceived to materially interfere with such directors' ability to act with a view to the best interests of the Company. The Board has concluded that a majority of the directors of the Company are outside and unrelated.

Committees of the Board: The Board has established and adopted terms of reference for each of the Audit, Executive, Environment, Compensation and Corporate Governance Committees. These terms of reference were recently reviewed and amended to ensure that they accurately set out the mandate for each of the committees.

The Audit Committee is composed of unrelated directors, of whom a majority, including the Chair, are outside directors. One of the three committee members is a full-time officer of Westcoast. This committee is broadly responsible for ensuring that the Company's management has designed and implemented an effective system of internal financial controls, for reviewing and reporting on the integrity of the consolidated financial statements of the Company, for ensuring compliance with regula-

tory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts and for reviewing the appropriateness and effectiveness of the Company's policies and business practices which impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management.

The Executive Committee is narrowly mandated to act as the approving body for expenditures which have been broadly approved by the Board and which are beyond the approval levels of the President and Chief Executive Officer and to perform such functions and exercise such powers specifically delegated to the committee by the Board. It is composed of three directors, one of whom is a full-time officer of the Company and another who is a full-time officer of Westcoast. The Board has determined that a majority of the committee members is unrelated.

The Environment Committee is composed of three directors, one of whom is a full-time officer of the Company. A majority of the committee members are outside and unrelated. This committee is responsible for reviewing and monitoring the environmental policies and activities of the Company on behalf of the Board.

The Compensation Committee is composed of directors who are unrelated. One of the three members is a full-time officer of Westcoast. This committee is generally responsible for recommending to the Board human resources and compensation policies and guidelines for application to the Company and for implementing and overseeing human resources and compensation policies approved by the Board. In addition, it is responsible for periodically reviewing the adequacy and form of the compensation of directors and for ensuring that the compensation realistically reflects the responsibilities and risks involved in being an effective director of the Company and for reporting and making recommendations to the Board accordingly.

The Corporate Governance Committee is composed of unrelated directors, a majority of whom, including the Chair, are outside directors. One of the members of this committee is a full-time officer of Westcoast. This committee's prime responsibility is for developing and monitoring the Company's overall approach to corporate governance issues and for administering a corporate governance system which is effective in the discharge of the Company's obligations to its shareholders.

The nominating responsibility of this committee includes proposing new members to the Board, establishing criteria for Board membership, recommending composition of the Board and its committees, assessing directors' performance on an ongoing basis and developing an orientation and education program for new members of the Board.

Chairman: The Board has determined that the present Chairman of the Board is an outside and unrelated director and independent of management.

Shareholder Feedback and Concerns: In conjunction with the Westcoast investor relations department, the Company maintains an active shareholder relations program. The program is designed to ensure that shareholder inquiries receive a prompt response from an appropriate officer of the Company.

Decisions Requiring Board Approval: The Board operates by seeking the advice of and delegating powers, duties and responsibilities to committees of the Board, by delegating certain of its authorities to management and by reserving certain powers to itself. In addition to those matters which must by law be approved by the Board, the Board retains the responsibility for managing its own affairs including selecting its Chair, nominating candidates for election to the Board, constituting committees of the Board and determining director compensation.

Expectations of Management: Members of the management team report to the Board on a regular basis to review the Company's financial and operational results and the Company's progress in fulfilling its strategic goals and objectives. The Board develops processes for defining its expectations of management such as reviews of the Company's strategic plan with management and a comprehensive review of the performance of the President and Chief Executive Officer, which review is carried out by the Compensation Committee.

Concluding Statement: The Company has adopted or is in the process of adopting the recommendations for improved corporate governance established by the TSE.

Corporate Information

DIRECTORS

Robert F. Chase ^{1,5}
President and Chief Executive Officer
Lexacal Investment Corp.
Vancouver, British Columbia

Roy G. Dyce ^{3,4}
President and Chief Executive Officer
Pacific Northern Gas Ltd.
Vancouver, British Columbia

Roy Illing ²
President
Roy Illing Consultants Limited
Victoria, British Columbia

Hugh C. Morris ^{1,2,3}
President
Padre Resources Corporation
Delta, British Columbia

Robert F. O'Shaughnessy ³
Professional Engineer
Galiano Island, British Columbia

Kenneth E. Rekrutiak ²
Senior Vice President
Westcoast Energy Inc.
Vancouver, British Columbia

Richard D. Walker ^{4,5}
Chairman of the Board
Pacific Northern Gas Ltd.
Vancouver, British Columbia

Arthur H. Willms ^{4,5}
President and Chief Operating Officer
Westcoast Energy Inc.
Vancouver, British Columbia

Graham M. Wilson ¹
Executive Vice President and
Chief Financial Officer
Westcoast Energy Inc.
Vancouver, British Columbia

OFFICERS

R.D. Walker
Chairman of the Board

R. G. Dyce
President and Chief Executive Officer

G. B. Weeres
Vice President,
Operations and Engineering

J. L. Peverett
Treasurer

P. A. Horner
Comptroller

D.G. Unruh
Secretary

K.L. Wharton
Assistant Secretary

HEAD OFFICE

1185 West Georgia Street
Suite 1400
Vancouver BC V6E 4E6

Telephone: 604-691-5680
Facsimile: 604-691-5863

PRINCIPAL FIELD OPERATING OFFICE

2900 Kerr Street
Terrace BC V8G 4L9

REGISTRAR AND TRANSFER AGENT

Montreal Trust Company
Vancouver, Calgary,
Regina, Winnipeg,
Toronto, Montreal

AUDITORS

Ernst & Young LLP
Vancouver BC

ANNUAL MEETING

The Annual Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held in the Cypress Room at the Hyatt Regency Hotel, Vancouver, British Columbia on Thursday, April 22, 1999 at 10:00 am (Local Time).

¹ Audit Committee

² Compensation Committee

³ Environment Committee

⁴ Executive Committee

⁵ Corporate Governance Committee



Pacific
Northern
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